A Proposed Action Plan to Develop More Demand Response in California's Electricity Markets

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Michael Messenger
California Energy Commission
Demand Response Program Manager

Readers Guide to the Final Draft of the Demand Response Action Plan

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This draft contains seven sections:

1. Introduction - What is demand response?
2. Roots of the Problem - Why weren't California's markets demand responsive in 2000 and 2001?
3. Magnitude of the Problem and Potential Opportunities - What were the consequences of a lack of demand response capability in current electricity markets? How did the current generation of demand response programs perform?
4. Vision Statement - What will wholesale market, delivery infrastructure and metering system look like in year 2001 and beyond?
5. What are the barriers to achieve that vision?
6. What action steps should be taken to address each key barrier?
7. Next Steps

Readers who are already conversant with the arguments for achieving more demand response may want to skip over the first three sections and concentrate on Sections 4, 5 and 6. Readers with a very short amount of time should just read the introduction and Section 6- the Proposed Action Plan to address key barriers.

Thanks,
Mike Messenger

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Final Draft of a Proposed Action Plan to Develop more Demand Response in California's Electricity Markets

I. Introduction: What is Demand Response and is More Needed in Electricity markets?

Demand Response refers to the capacity of electricity customers to reduce their consumption as prices rise on an hourly basis in wholesale markets or to reduce their consumption in response to emergency calls for curtailment to forestall the need for rolling blackouts.

For years an individual customer's ability to reduce demand in response to changing prices was not important because retail prices did not change more than once a year and fluctuations in wholesale prices were not passed through to customers. Customers had the luxury of responding to changes in electricity prices within planning time frames of weeks to months. However with the development of "deregulated" wholesale supply markets in California wholesale prices began to change dramatically on an hourly basis.

In theory retail rates should have at least tracked these changes in wholesale market on a lagged basis to ensure that the markets functioned and brought downward pressure on rising prices by reducing demand. In practice retail rates were frozen so wholesale price changes were not passed through until it was too late, in June of 2001, after 12 months of price volatility. Customers had to rely on third parties and or "make shift" emergency programs to provide intermittent signals that prices were headed up. Moreover many customers did not have the requisite metering equipment to partially reduce their load in return for energy or capacity payments offered. Without price signals and the equipment to react to them, crude all or nothing demand response in the form of rolling blackouts became not only important but vitally necessary to ensure system reliability.

In sum the California wholesale electricity market was not demand responsive during the summer of 2001 and 2002 for two critical reasons:

1. Customers lacked the metering and controls equipment or technology to effectively respond to changes in prices in the relevant time frame.
2. Changes in wholesale prices were not automatically passed through to retail customers due to the retail price freeze.

Efforts to reform this market by addressing these problems came too late to discipline or restrain wholesale price spikes on both the supply and demand-side. Significant reductions in customer demand in most of the California did not appear until 6 to 9 months after the wholesale prices first spiked in the summer of 2001. What the market needed was demand reductions within minutes to hours of first price spikes in May of 2000, what actually happened was that Demand levels dropped by 4000 to 5000 MW but way too late; 9 to 12 months later in May of 2001. Unfortunately this "demand response" was well after the electricity crisis had peaked and billions of dollars had been transferred from consumers to producers.

One of the critical lessons learned from the experience in the California markets is that it is crucial that customers or aggregators of customers have the capacity to protect themselves from wholesale price volatility through the purchase of futures hedges or energy controls equipment that will allow them to respond quickly to changing prices, since timing is everything in competitive wholesale markets. This protection is arguably superior to relying on regulators to discipline the market through the introduction of price caps. Competitive markets cannot function without customers who have both access to timely price signals and the capability to reduce their aggregate demand as prices rise. Without these customer capabilities, the demand for electricity or any other commodity is very inelastic and gives producers essentially a license to make " free" money by raising prices without any fear of losing revenues due to corresponding reductions in demand in the relevant time frame. eg within the next few hours on the wholesale market. The critical question is whether policy makers will act in time to avert the next crisis.

This report lays out an action plan to minimize if not eliminate the possibility that tenfold electricity price increases in the wholesale market could ever again be maintained over a period of days or even months in California. We will seek comments and input from all interested parties on which of the actions are the most important to take in the short and long run. But first, it is important to step back and look at the roots of the problem, in Section 2, describe the size of the problem created by a lack of demand response, in Section 3, and describe our vision of how California electricity markets may evolve over the near and long term, in Section 4.

II. The Roots of the Problem

A. Power production and or the cost of purchasing imported power during periods of peak demand for most utilities ranges from 5 to 20 times the cost of producing electricity for during baseline load conditions. Indeed over half of the annual generation costs can be incurred over only 10% of the operating hours when costs rise during system peaks.

Figure 1 and Figure 2 illustrate the fundamental fact that the cost of producing electricity to meet peak demands ranges from 5 to 15 times more expensive than the cost of production for the remaining 90% of the year for many distribution companies. Figure 1 presents actual data from the Pennsylvania, New Jersey and Maryland PJM system. (Reference 1)

Figure 1

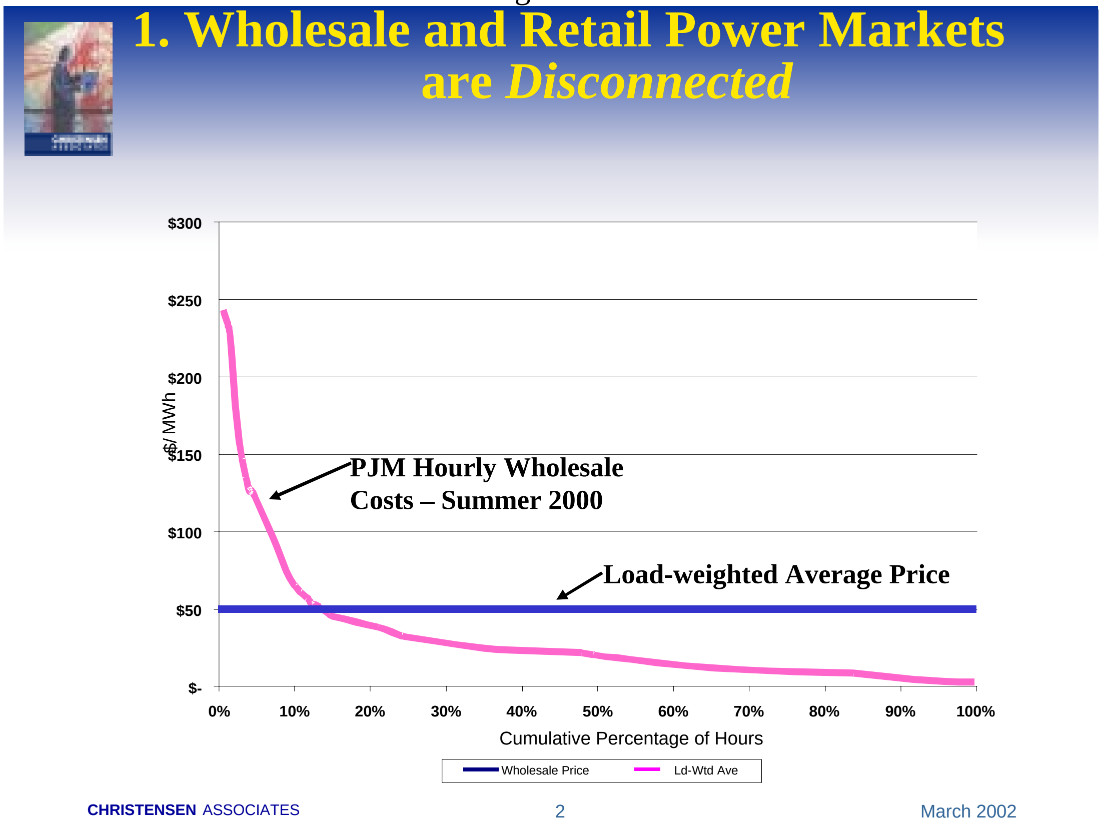
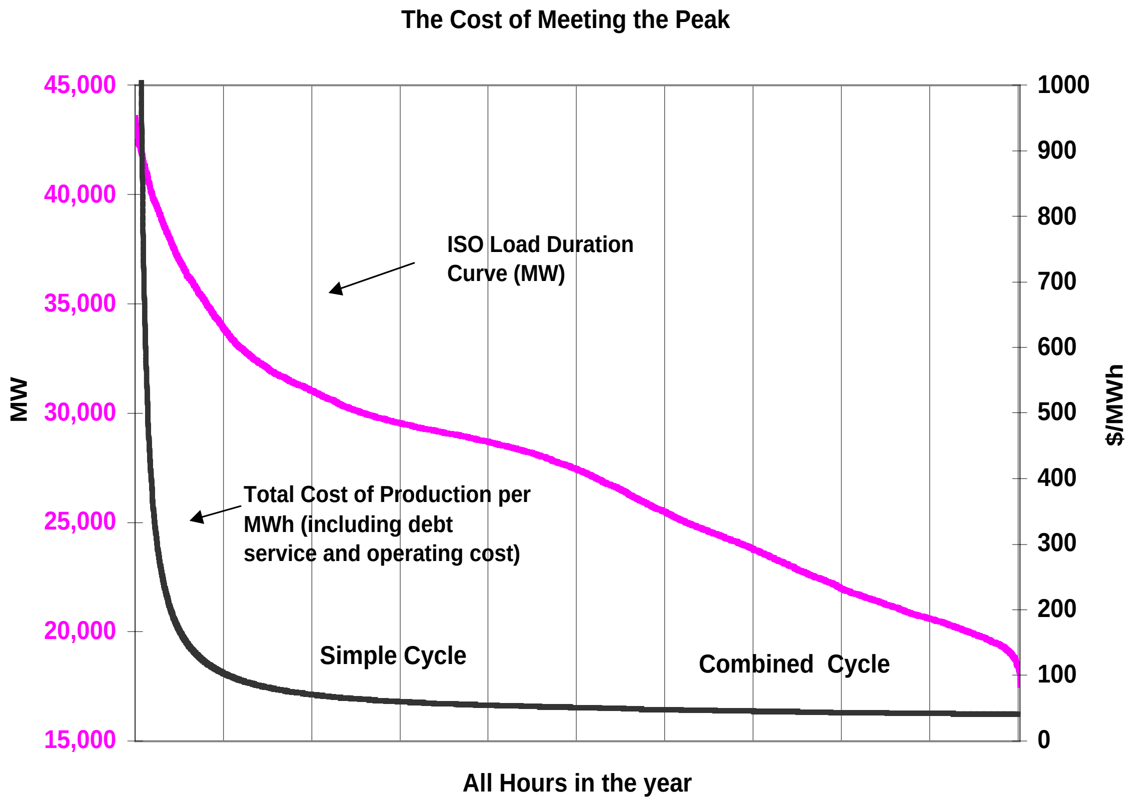


Figure 2 presents the estimated generation costs for the California system at different levels of demand. (Source: Pat Macauliffe, Energy Commission staff) By comparing the graphs we can see that the pattern of high costs per MWh to meet "needle" peaks occurs in many distribution systems and occurs whether or not the wholesale market contains unregulated generators or regulated, vertically integrated monopolies.

Figure 2



B. These higher production costs for generation resources or imports operated during the 50 to 100 hours of peak demand have historically not been revealed to customers through rising tariffs at the time of high costs but rather rolled into the total operating costs for the year. Thus price changes in the Wholesale market were not and are not routinely passed through to customers in the Retail market

This practice of "rolling" short periods of high wholesale price costs into retail rates "averaged" over an entire year may have made sense in a regulated environment because most generators were constrained from raising prices above costs during times of scarcity at peak. However in a competitive market where generators are seeking to maximize profits this inability to adjust demand in response to price increases proved **fatal** for the system, since neither customers or regulators could react quickly enough to respond to rising wholesale prices. What could have been a "minor" price run up in the first two summer months of 2000 that was matched by a corresponding drop in demand was quickly transformed into a reliability crisis as generators "learned" they could take advantage of, (profit from) extremely inelastic demand levels and began to withhold power in certain markets to take advantage of highly inelastic conditions in the real time or spot markets.

What lessons can be learned here? Making price signals available to customers is essential to maintaining balanced and healthy markets. Changing prices in the wholesale market signal abundance and scarcity in commodity markets and help guide investment in alternative products or systems to increase the efficiency. Rising wholesale prices are not always “evidence of a dysfunctional market.” Rising wholesale prices usually are important signals that help redirect both energy use and investment in the short and long run. Customers are nearly always better off when they have access to wholesale price signals rather than flying blind and counting on others to take action s to reduce their prices!

C. Customers currently are not allowed to choose what level of price risk they want to accept in their standard or default rate structure.

Customers should be able to choose their own rate structure and associated levels of price risk (just as they do for insurance policies or cell phones). Shielding customers from “unacceptable” market price fluctuations inevitably leads to rationing solutions (e.g. blackouts for selected customers) rather than investment in new technology. Customers should be offered rate choices that allow them to choose between paying premium prices for flat tariffs or being willing to expose themselves to more price volatility in return for lower prices overall.

D. Federal and state regulators have not been able to agree on the best policy response to a dysfunctional wholesale market

To put it mildly, the federal government has been focused on attempts to reform the structure of the market while many state regulatory commissions have pushed for price caps that make it difficult if not impossible for the market to send price signals to consumers.

E. The Current market structure is inequitable because there are barriers to entry for “ demand” aggregators (UDCs or private firms) interested in facilitating demand response at the wholesale market level.

Customers and aggregators of customer load have not been allowed to participate in wholesale markets on an equal basis with power generators in part because regulators have assumed that customers must look like and act like generators before they are eligible The Markets for ancillary services support and capacity reserves are beginning to be made available to all bidders in some wholesale markets but aggregators face significant market risks due to uncertainties in policy direction and lack of capital reserves relative to their generation competitors.

F. Current market clearing prices revealed in shallow (low volume) wholesale markets are not likely to reflect the true marginal costs of

supplying additional power because of the imposition of FERC price caps and other mitigation measures.

Wholesale markets in California have witnessed two extreme states within 12 months; from a situation where almost 70% of total power purchases flowed through the spot markets to a situation where less than 1% of California's power requirement flow through these markets. The Federal Energy Regulatory Commission's (FERC) decision to intervene in these markets until a more rationale mix of long, medium and short supply contracts were executed had the short term beneficial effect of stabilizing prices but may represent a much longer term threat to system reliability in California since marginal prices are no longer revealed to all market actors. These price caps and the threat of their re imposition will make it more difficult to predict the effect of increased demand response capability or drops in load during critical peak periods.

G. So much attention has been focused on ”policing” the questionable bids or behavior of generators that regulatory authorities may have spent too little time attempting to reform the demand side of the market.

Most analysts agree that more demand responsiveness is needed in electricity markets but almost all regulatory actions taken to date have focussed on “controlling” the prices generators can bid rather than taking action to encourage more response from customers when or if these prices rise. is needed on the demand side of wholesale markets. But no one regulatory body has oversight responsibility or authority to make this happen. Demand response providers in the form of aggregators of customer demand response could be allowed compete on an equal footing with suppliers to provide ancillary services. FERC has recently begun to move ahead in this area with the introduction of a standard market design but progress may be limited due to the ongoing disagreement over which federal or stated agencies have jurisdiction over demand response programs.

H. State agencies have had limited success in achieving a consensus on the need to stimulate more demand responsiveness in the California market.

This failure is in part structural, because of the existence of agencies with overlapping jurisdictions related to system reliability and procurement, and in part financial, due to utility creditworthiness problems. The financial part is driven by utility credit problems and the state's subsequent need to take over the UDCs energy procurement functions. This lack of available capital has made it difficult for organizations to invest in the different types of demand response capability that could solve the problem.

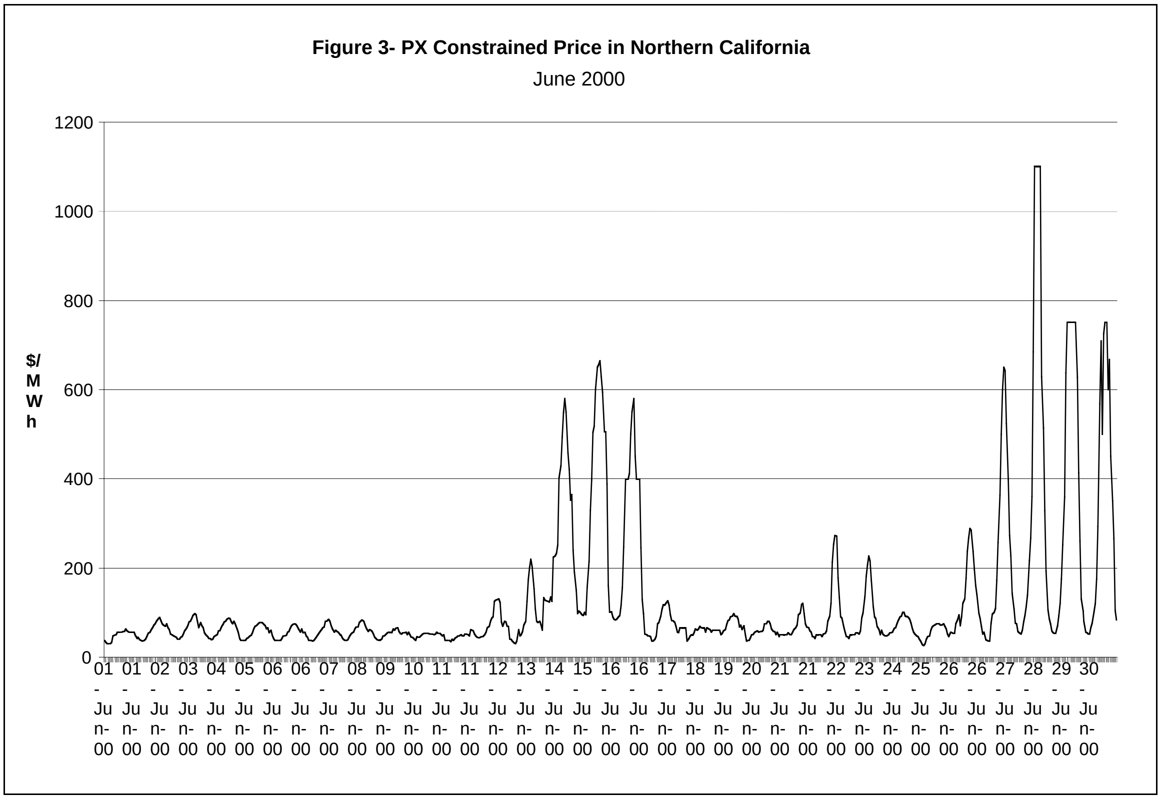
Fortunately, the energy agencies in California have a historic opportunity to work together to solve this market problem because for the first time there are a number of outside organizations encouraging them to work together for the good of the whole. For example, members of the legislature have recently sent a letter to the Energy Commission, CPUC and CPA encouraging them to work together and develop a unified policy for demand response and energy efficiency programs. It remains to be seen whether this hope can be realized.

Summary- The flat electricity rate structures offered by UDCs to almost all customers mask, and in some senses subsidizes, the real cost of producing electricity during peak periods. This policy made it almost impossible for the wholesale market to exhibit any timely demand response to rising prices in the wholesale market during the summer and fall of 2000 and the spring of 2001. This lack of price disclosure to customers contributed to the high prices and profits reaped by generators in the California market from May of 2000 to June of 2001. Any attempt to reform the wholesale market must address the problems revealed on the demand side of this market in addition to the strategic behavior or withholding witnessed on the supply side.

III. The Magnitude of the Problem: How much money could have been saved if Demand Response programs and/or Dynamic Pricing had been in place in California last year?

California experienced extreme price volatility in wholesale electricity markets in 2000 and 2001 **Figure 3 illustrates this pattern for the year 2000, before and after the imposition of price caps.** One of the reasons for the extreme price volatility is that these new markets for supply were not demand responsive within minutes to hours, i.e. when prices went up there was no corresponding drop in consumer demand within the hour or in some cases within days of these price spikes. As a partial result of this lack of demand response, the total bill for utility power purchases nearly quadrupled from $7.4 billion in 1999 to $27 billion in 2000. Total electricity costs stabilized at $26.7 billion in 2001 even though the average cost per MWh was slightly higher at $114/MWh in 2001 than the $107/MWh reported for 2000. This was due in part to lower peak demands in the summer of 2001 and the FERC price mitigation/caps that took affect in June of 2001.

Figure 3



Analysts have attempted to estimate the amount of money that could have been saved if the wholesale market, in hindsight, had shown this capability to respond to these rapid increases in price by reducing demand as prices rose. This is always a difficult exercise because many exogenous factors affect wholesale prices. In addition to normal market forces, there are a number of allegations that suppliers were engaged in strategic withholding and or taking advantage of structural flaws in the wholesale market over the last two years. However it is possible to either construct an aggregate demand curve based on the prices and quantities observed in this market before price caps or use previous short run elasticity estimates to bound the expected change in demand and thus prices in a demand responsive market. We provide a discussion of three ways to estimate the benefits from increased demand response capability below.

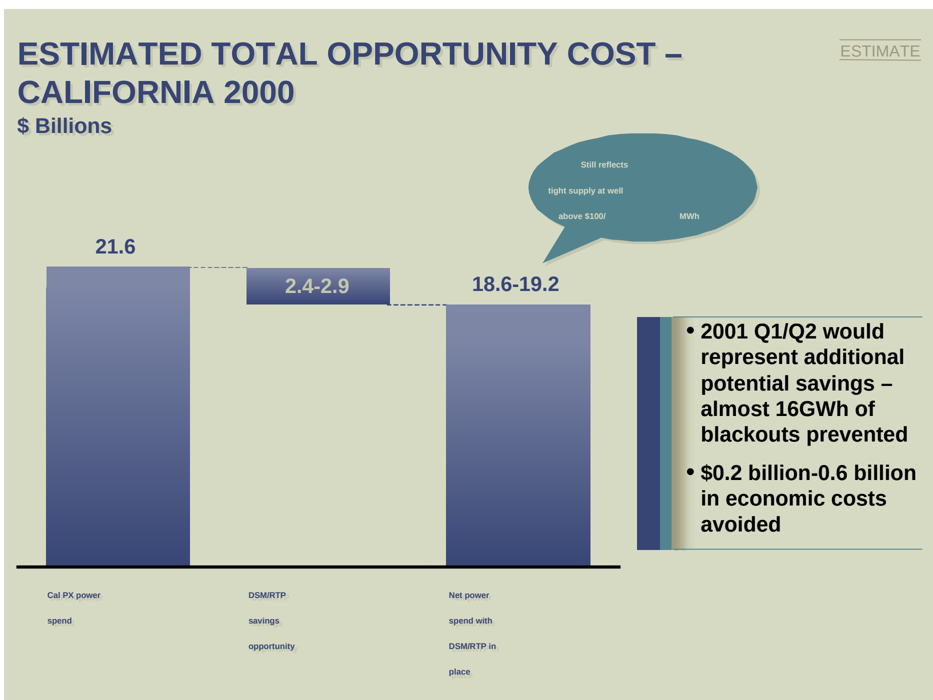
a. Method 1- Assume that the changes in wholesale market prices observed in 2000 were passed on to customers and estimate the corresponding reduction in demand and market prices using historical price elasticities. (Source, McKinsey)
b. Method 2- Estimate the actual elasticity of demand and supply using CPX data in 2000 and determine the dollar savings associated with incremental levels of demand reduction (Source: Energy Commission staff)
c. Method 3- Analyze the costs of operating new peaking facilities during the 20 to 100 hours of needle system peaks in today's market and estimate the

marginal value of saving demand at the margin by avoiding these costs next year and beyond. (Source; Energy Commission staff)

Method 1- Assume that the variations in wholesale price observed in the market were instantaneously passed on to all customers in rates and use historical price elasticities to estimate the corresponding reduction in demand and dollar savings

Figure 4 displays the results of an analysis for McKinsey Consultants who were commissioned by the Association of Bay Area Governments to analyze the behavior of wholesale markets. (Reference 2) Their analysis suggests that the observed wholesale power costs of $ 25.2 billion for California in 2000 would have been reduced by somewhere between $2.4 and 2.9 billion if hourly pricing had been in effect for medium and industrial customers. More importantly the estimated reduction in demand from this customer response would have precluded the need for any calling any blackouts in the spring of 2001.

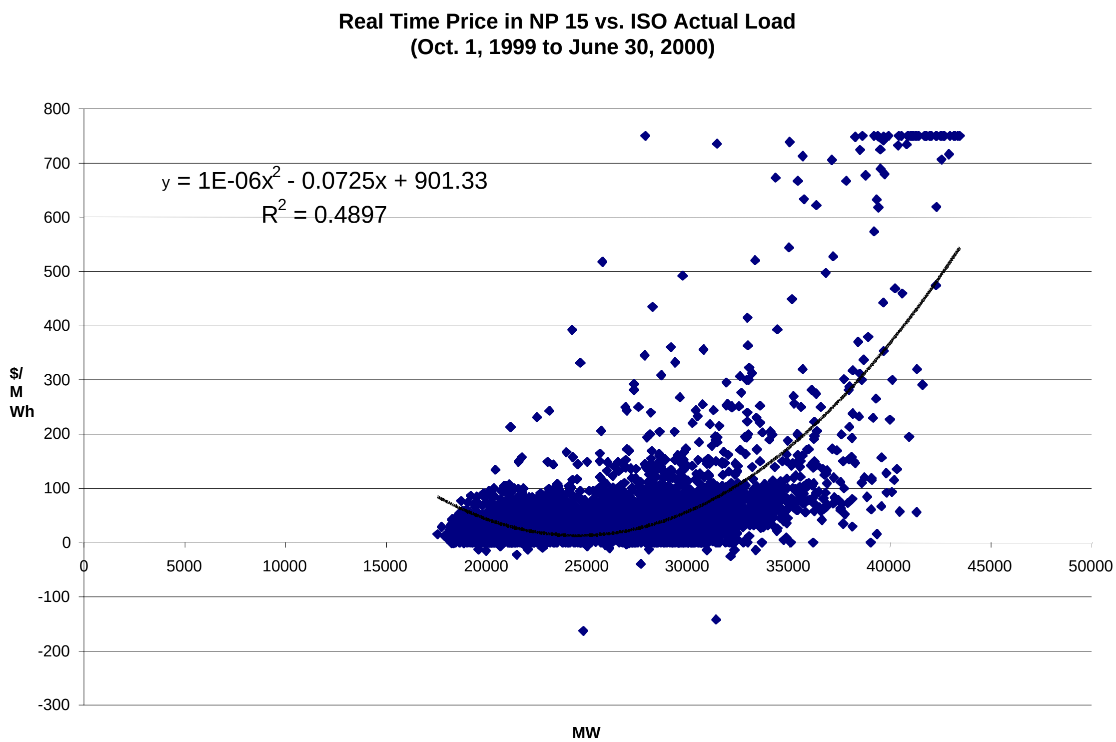
Figure 4



Method 2- Use Historical price and Quantity data from the California market in 2000 to estimate the value of demand response at the margin

Another way to estimate the potential savings from the introduction of demand response programs and or dynamic tariffs is to construct a demand curve and estimate the drop in wholesale prices for a given level of demand reduction achieved by programs or tariffs. Figure 5 shows the estimated demand curve for ISO loads and real time prices in Northern California for the time period of October 1, 1999 through June 30, 2000.

Figure 5



When an exponential fit line is used to analyze this data, the R^2 is almost 50%. (The coefficients of the best-fit equation are shown in the figure) This suggests that roughly 50% of the price variation in this plot can be explained by "rational" expectations that market prices will rise as demand increases and vice versa. The other 50% of the unexplained variation relates to other factors at work in this market (e.g. market power, poor market design, strategic withholding) that may have been a historical accident or simply the fact that wholesale prices were not passed on to customers in a timely manner.

Evaluating the fit line for the range of load in excess of 32, 000 MW, a linear fit approximates a change in price of $35 per MWh per change of quantity of 1,000 MW. This relationship holds for all demand changes between 32,000 and 45,000 MW. Table 1 shows the estimated impact on prices at different levels of demand response. This calculation is conservative because it only looks at changes in prices that could be expected on the ten typical peak days in California where peak load exceeds 40,000 MW. In reality more dollar and peak savings would be realized if customers were placed on dynamic rate structures where changes in wholesale prices would automatically be passed on to customers on each day of the year rather than the 10 hottest days.

Table 1
Change in Wholesale Market Prices as a function of
Aggregate Demand in the CAISO load control area

Hypothetical Demand Response Program Impacts (MW)	Baseline Price $/MWh	**Estimated price drop as a function of demand response $/MWh**	Expected System Savings from drop in wholesale prices ($ million)[1]
Baseline condition -40,000 MW	***370***	***0***	***0***
2000 MW (current programs=1500 MW)	300	70	168
5000 MW (current programs + voluntary hourly pricing industrial	205	165	420
8000 MW (Voluntary Residential critical peak pricing and voluntary hourly pricing for medium and large customers	90	280	672

For reference, California utilities estimated that the aggregate capability of their load management programs in the spring of 2000 was roughly 3000 MW with most of this capacity coming from interruptible rate programs. Available capacity had dropped to 1500 MW after extensive use of interruptible rates from January to May of 2001(See appendix A for a chart of reported demand response capability over time.) Metering advocates estimate that demand response in California could easily be increased by an additional 5000 MW if 30% of large and commercial customers were allowed to join dynamic tariffs: (either hourly or critical peak pricing). (Reference Chris King, emeter presentation)

Unfortunately the existing "demand response" capability of California's utilities has been primarily designed to reduce demand during emergency conditions and as a result was used only a few times in the last two years. The maximum load drop ever achieved through the use of interruptible programs was 1730 MW on May 8, 2001. (Source CAISO report on ISO Declared Emergencies of 2001, Reference 3). Utility load

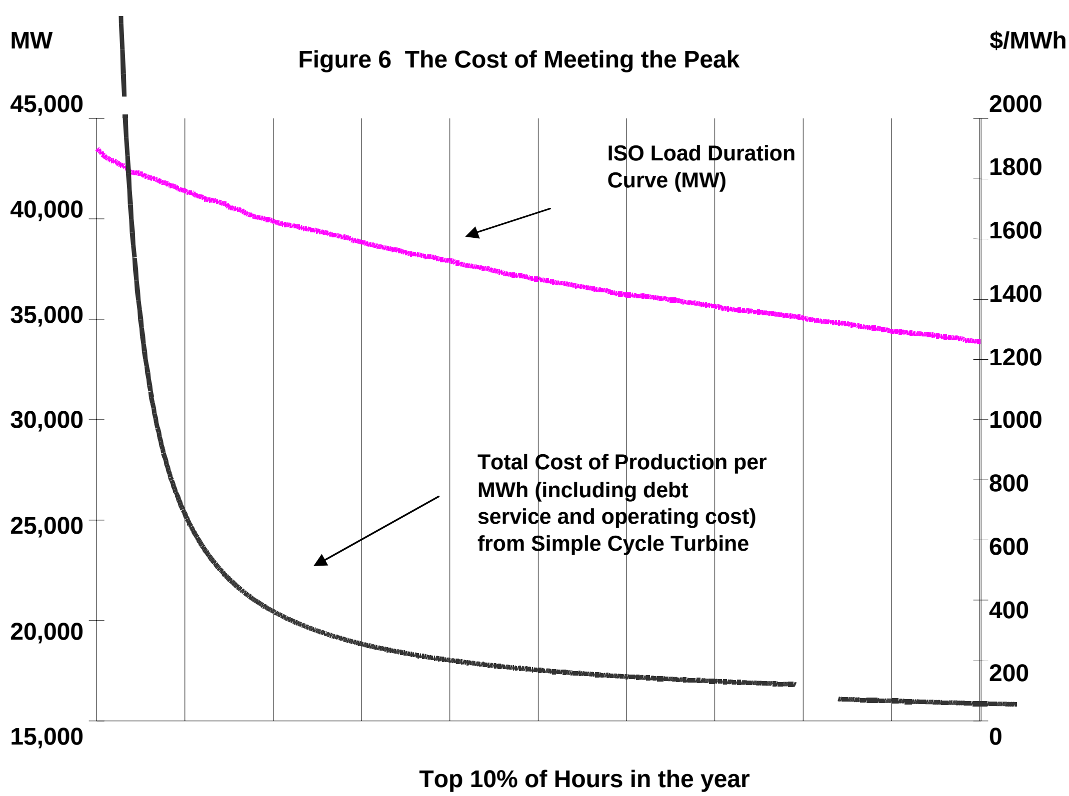
[1] Calculation derives energy consumption for a typical peak day using 40,000 MW over 6 hours= 240,000 MWh

management programs have not been used to mitigate or restrain wholesale prices. The sum of the aggregate load drops from both interruptible curtailable rates and direct control programs programs never exceeded 2000 MW on a statewide basis. More dollars could be saved by restraining or reducing wholesale price increases if demand response programs became an everyday tool used to combat price volatility as opposed to being used exclusively as a form of emergency insurance.

Method 3- Using the cost of operating combined cycle gas turbines during peak conditions as a proxy for the value of demand response at the margin.

An alternative approach to estimating the value of demand response at the margin is to assess the total cost of a new peaker (simple cycle turbine) against the number of hours of possible operation in a particular year. Figure 6 above takes total annual costs of operating the plant including debt service plus fuel use (depending on output) and divides by hours of operation (1, 2, 3, …) to arrive an average cost of production ($/MWh) depending on numbers of hours of plant operation. This analysis suggests the value of demand response at the margin is over $1600/ MWh when demand exceeds 40,000 MW in California This analysis illustrates the cost of meeting peak demands if the system operators chose to fund the construction of peakers but only operated them for 50 to 100 hours per year as opposed to seeking more demand response through programs, bids or prices.

Figure 6



Summary- This analysis of the effectiveness of drops in demand at the margin shows that the value of reducing peak demand at the margin ranges from $35/MWh (Method 2) to $2000/ MWh based on the cost of running peak power plants to meet incremental load for 10 to 20 hours per year. (Method 3) Currently the state lacks the capability to actually achieve these price drops because there is no set of programs or tariffs in place with a significant capability to reduce load at the level of three to five thousand MW as prices are rising in wholesale market. The peak level of load reduction achieved by all of California's demand response programs in March of 2001 was less than 2000 MW.

This estimated value for demand response programs of $35-2000/MWh compares to current incentive levels of $35/MWh in cash payments currently offered to customers for participation in the base load interruptible programs during this same time period. Thus the payments authorized to achieve demand response are considerably less than their value to the system. This is a classical public good problem that usually requires intervention to achieve benefits for all ratepayers by encouraging some private firms to go beyond what normal market prices would stimulate.

This analysis of the value of demand response is conservative because it does not account for the actual benefits to California's economy or customers of avoiding rolling blackouts. Rolling blackouts are the most extreme form of demand response programs, e.g. mandated total load curtailments with less than 1 hour notice and no alternatives. Estimates of the cost to the economy or commercial firms of blackouts currently exceed $10,000/ MWh.

Our review of the data suggest that increasing the state's demand response capability to 5000 MW has the potential to significantly reduce wholesale market costs. Estimates of the level of annual benefits from a demand response program based on 2000 data range from $ 420 million (see Table 1) to $2.9 billion, without accounting for any estimate of the damages avoided by virtually eliminating the need for rolling blackouts. In addition DR programs and or dynamic tariffs have the potential to significantly reduce, if not eliminate, the need to resort to rolling blackouts if or when adequate suppliers are not available in the wholesale market. These potential benefits of deploying dynamic tariffs and interval meters on a large scale of roughly 5000 MW need to be balanced against the costs of deploying advanced metering and control systems that could give customers the capability to respond to changes in wholesale prices.

B Costs of Installing Interval Metering systems

The cost of installing a large number of advanced or interval metering systems depend on the number of systems to be deployed, the communication medium to be used, the built in software capabilities to monitor and display energy usage, and the type of customer and the length of the contract provided to meter service providers. The Energy Commission's experience in procuring interval meters and communication systems for medium and large commercial customers suggests that the range of meter cost bids range from $1.00 to $ 3.70 per meter per month for a five year contract to a range of 70 cents to $2.60 per meter per month for a 12 year contract. (Reference 5) This range compares to the estimated current cost of $.74/ meter /month for traditional meters with no interval capability. These figures suggest that large scale deployment of these meters may be cost competitive at current prices without any consideration of the additional functionality and or demand response benefits associated with their use based on two condtions: (1) they are purchased on a large scale (> than 200,000 meters) and (2) and their costs are amortized over a contract period of 12 years.

The total costs of installing meters for the remaining small and medium customers between 50 kW and 200 kW can be approximated as $2.50/meter per month over 10 years multiplied by the 50,000 remaining customers, or $ 15 million dollars. This compares to the projected benefits for installing meters and developing critical peak tariffs for these customers who represent 6000 MW of peak load or roughly 600 MW of demand response. Using the conservative figures from Table 1 for the value of demand response at $35/MWh yields benefits of $48 million per year or a net present value of $325 million over the ten-year period.

Meter vendors have asserted that these installation costs should be compared to their estimates of $6 to $8/meter per month of benefits from their deployment. (Reference 6) E meter estimates that the social benefits of installing interval meters to all customers will exceed these costs even if only 30% of these customers actually sign up for a dynamic tariff. These assertions should be closely analyzed by an interagency group of analysts before making a decision to universally deploy IDR meters for all customers. But the key point is that the costs of these meters is already close to their ancient competitors and almost any level of demand response benefits is likely to tip the scales in favor of mass deployment using the estimated presented here.

The costs of installing advanced metering systems and supporting communication networks in residential applications is not as certain. Puget sound has had some experience in installing these meters and reports the costs of installing these meters has already been repaid by operational savings in less than 3 years. (Reference 10)

Figure 9, in the next vision section, suggests the cost of the interval meter itself will be around $100 per house. The cost of communications, software and controls at the home are not yet known with certainty. For Gulf power's system, residential customers pay $4.53/month for seven years (roughly $400) to cover the cost of the interval meter, a whole house surge protector, a smart thermostat and two controllers that can respond to critical peak prices by reducing consumption at up to two large end uses per home. Total installation costs are closer to $600/ home suggesting the utility is picking up $200 / home based on other benefits being produced by the system.

Actual costs of systems installed in California will depend on whether utilities purchase and install these systems in bulk and what fraction of the total costs are paid for by the utility as part of its" metering system" and what costs are paid for by homeowners for software, display and control systems.

IV. Our Vision: What should the electricity distribution and metering services market look like over the next 5 to 20 years?

A. Market Structure- Energy Commission staff envision a market with the following roles and responsibilities for each key actor.

1. Distribution utilities will offer their customers a wide spectrum of rate options/ programs and the corresponding meter and communication technologies to support them. The goal will be to offer customers a menu of choices that reflect their willingness to shoulder the risk of price increases in the future and contribute to system reliability for the entire community.

2. Demand response technology vendors (e.g. metering providers) will be able to market their equipment and or services to customers or distribution utilities and amortize the costs of these systems as a monthly service charge on the UDC bill. Technologies that will make customers, or their building managers, aware of changing electricity prices on an hourly or day ahead basis and/or automatically adjust consumption based on customer choices about the tradeoffs between different levels of consumption and rising prices.

3. The state will require all new buildings constructed after 2006 have automatic load control devices built into the building energy management system to "absorb" wholesale price shocks and provide emergency load relief. Builders will install these automatic load "shock absorbing" devices in new buildings that will have the capability to automatically reduce load for non essential systems by 10 to 20% in response to price or emergency signals. Customers can pre program their EMS systems to acceptable levels of curtailment, based on their choice of available rate structures and willingness to curtail load in response to price or emergency signals.

4. Regulators will carefully review "demand response" portfolios filed by UDC's that balance the desire to minimize costs and ensure rate stability. These portfolio's will be considered as part of each UDC's overall electricity supply procurement strategy to balance short, medium and long term supply contracts

5. Customers can choose to participate in various forms of dynamic pricing; hourly tariffs, critical peak pricing, time of use pricing or choose a flat rate with an insurance premium built into the rate.

B. Rate Structures

1. UDC's will be obligated to pass changes in the wholesale electricity price directly through to some fraction of their customers who willingly choose to bear the risk

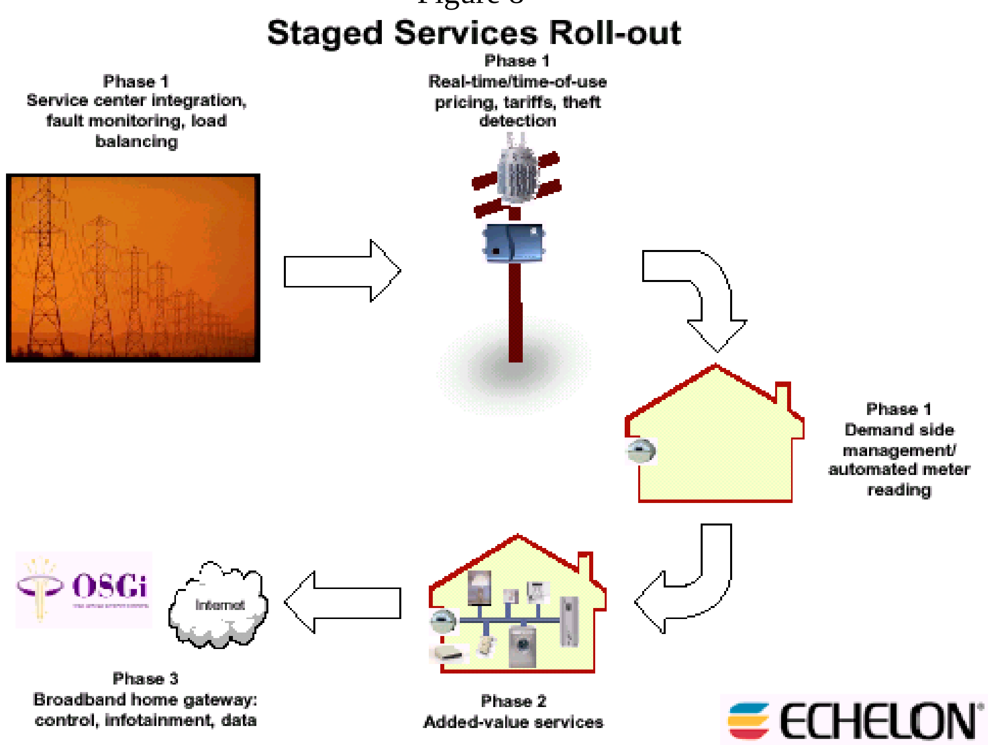
of higher prices during system peak conditions in return for the benefits of much lower prices during the majority of operating hours.

2. ALL customers will be allowed to choose how they prefer to manage the risks of future price increases by choosing either flat or variable rate structures (or somewhere in-between). Our preference would be **that time of use** rate structures become the default rate for **all customers**. These customers can then choose to participate in one of the following three types of rate structures to better match their preferences for managing price risk:
   - Voluntary base rate discounts coupled with critical peak pricing rates for a small fraction of the year
   - Two-part hourly pricing tariffs for the large commercial and industrial customers.
   - Flat rate structure for those customers who are willing to pay a monthly Stability Premium in exchanges for the certainty of a flat rate over a one to five year contract.

C. Metering and Information Technologies

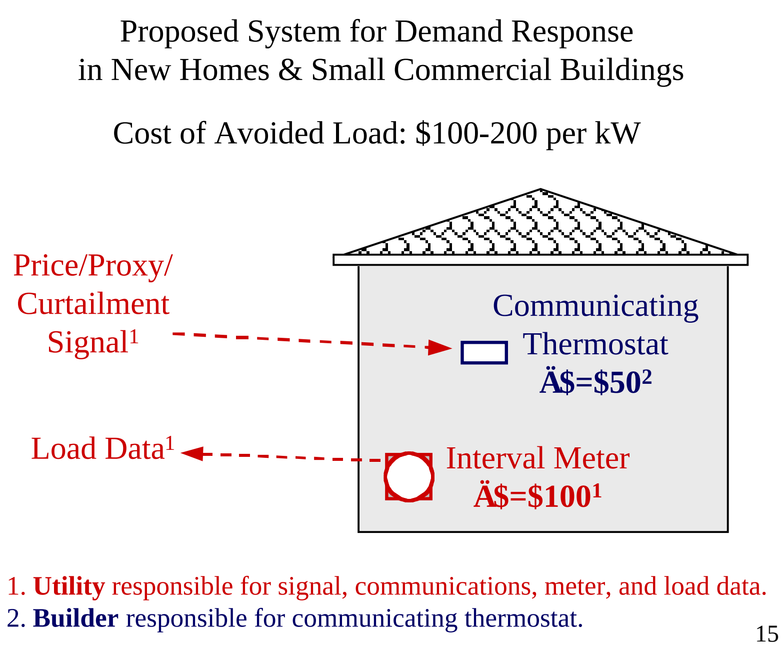
Echelon presents a potential vision of how metering and communications systems may be gradually deployed in the market place in Figure 8. The group should discuss and perhaps enhance this vision.

Figure 8



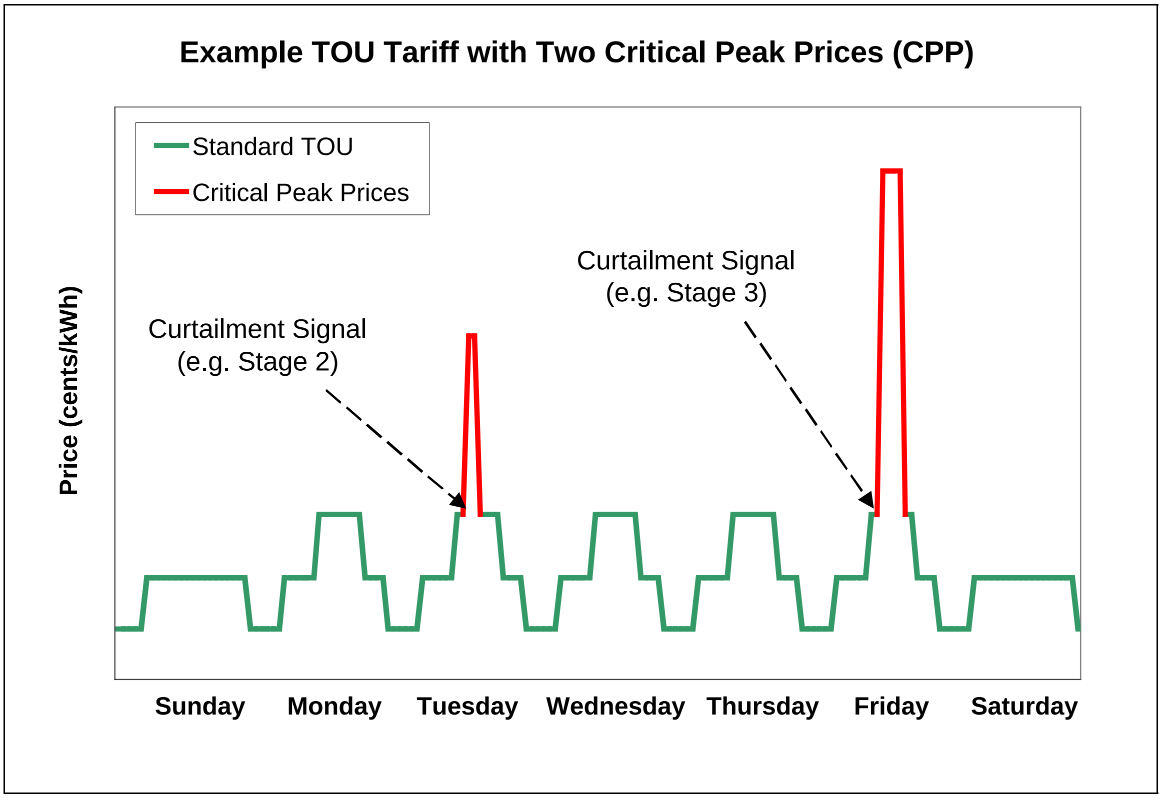
Energy Commission has a vision of how metering technologies might be deployed in the residential sector. We envision a demand response program required as a condition of service for all residential customers with central HVAC systems. Under this program, all customers with central HVAC systems would require (1) a dynamic tariff and (2) an advanced meter. A responsive thermostat would be offered to help these customers pre program their home system to respond to system price signals. This would allow customers to lower their bills at a minimum when they are not home and perhaps by more if they choose to program the thermostat set point to rise to 78 degrees once prices pass some threshold, say 20 cents/kWh.

Figure 9



To complement this infrastructure we propose to make critical peak pricing tariffs available to all residential homes. Figure 10 provides a picture of critical peak pricing rates. Customers are offered a discount or lower rates for the vast majority of hours in the year in return for the possibility that critical peak prices may be charged for up to 50 hours per year when system reliability is threatened or wholesale prices begin rising dramatically. This type of pricing is a compromise between customers who want the certainty of flat rates and the suppliers of energy who must deal with the reality that wholesale prices frequently rise and their costs must ultimately paid by retail customers

Figure 10



Example TOU Tariff with Two Critical Peak Prices (CPP)
Standard TOU
Critical Peak Prices
Curtailment Signal
(e.g. Stage 3)
Curtailment Signal
(e.g. Stage 2)
Price (cents/kWh)
Sunday
Monday
Tuesday
Wednesday
Thursday
Friday
Saturday

V. What are the current barriers to making this vision a Reality?

There are four general types of barriers to achieving increased demand response in the electricity market that were identified at our previous workshop. These are grouped into four types: Policy, Technical, Administrative and Marketing/ customer acceptance. Each is described below. **This section simply lists the barriers so readers with less time may want to skip to section 6 where we discuss both the barriers and actions to mitigate them.**

A. Policy Barriers

1. There is no common vision among regulatory agencies and probably most key market actors of how the wholesale and retail electricity markets will/should evolve after the chaos of the last two years and whether demand response programs, integrated with dynamic tariffs, should be part of this evolution.
2. There is a jurisdictional conflict between Independent System Operators regulated by FERC and Utility distribution companies regulated by state Public Utility Commissions over who should design and approve programs to increase demand response in wholesale markets. This conflict should be expected due the numerous gray areas that exist between transactions that occur in the wholesale market and the rates charged in the retail market to recover wholesale power costs.
3. This issue is even more complicated because of the possibility that some customers can participate in wholesale markets by providing demand response by contract while most customers participate in demand response programs in the retail market Currently it is not clear who has responsibility to develop different types of demand response programs or to make dynamic tariffs available to customers to ensure either system reliability and or reasonable prices.
4. The NYISO and PJM ISO have asserted that design of DR programs and tariffs is part of their mission to oversee the development of rational wholesale markets and thereby ensure reliability. The CAISO had developed some programs but had to suspend their operation due to creditworthiness problems beyond its control. In other areas, state CPUCs have retained jurisdiction over emergency programs. In California both state and federal agencies have developed and approved various forms of demand response programs. Historically the development and approval of load management programs has been the role of state public utility commissions as part of their charge to ensure high quality service at reasonable rates.
5. Some regulators are skeptical that dynamic tariffs and or the deployment of interval metering equipment to make them work would be cost effective to society. Others are skeptical that customers will really want access to dynamic pricing tariffs or equipment to control their loads in response to changing prices.
6. There is some uncertainty about whether demand response programs will actually create downward pressure on wholesale prices in today's "non-competitive" markets. An evaluation of the NYISO demand response programs showed that their emergency

demand response program produced a steady 45o MW of load drop during heat storms and 3% drop in wholesale prices (Reference 7). There has not been any analysis of the price impacts of using California's demand response programs impacts during the winter and spring of 2001. (Energy Commission staff has begun this analysis with partial results shown in Appendix 3.)

7. Some state regulators assert that there is no need to continue to try and fix the wholesale market as long as there is an option to return to a more regulated market that could " control" or discipline these markets, thus they see no need to have or develop price responsive demand or dynamic tariffs in the retail market.

8. There is no functioning wholesale market in California to provide hourly pricing signals or day-ahead forecasts of hourly prices. However, once implemented, ISO Market Design 2002 proposals have the potential solve this problem by providing reliable day-ahead and real-time dynamic pricing signals.

9. It is unclear how, or whether, dynamic pricing tariffs and price-response demand programs can be counted toward satisfying WSCC operating reserve requirements.

B. Technical Barriers

1. Digital Energy management control systems that can communicate with meters and system scheduling coordinators are still considered too expensive by many commercial builders.

2. The lack of an agreed upon uniform control language for EMS systems creates some communication problems with existing HVAC and lighting systems.

3. The incremental cost of installing dimmable lighting systems is still considered too high by most builders ($40-50 per ballast) to justify their expense as part of new building projects.

4. Some UDCs are skeptical that wireless metering technologies are reliable, cost effective and can deal with urban transmission shadows.

5. Immaturity in the "art" of estimating the extent of load reduction that may result from an emergency reliability signal or price signal reduces interest on the part of system operators and energy procurement agents.

6. In order to facilitate more customer participation, load visualization and alarm techniques, and automatic control equipment must continue to evolve to make demand response concepts more "user friendly."

C. Administrative Barriers

1. Billing System Capacity Constraints- UDCs could have trouble, in the near term, billing their customers using dynamic pricing tariffs if the tariff design was very complex or the number of participants exceeds a few hundred. Probably need a long-term decision to deploy advanced meters on a universal basis over five to ten years.

2. Multiple Programs- Multiple types of demand response programs are currently offered by UDCs and private aggregators to the public. To complicate matters they are overseen by different agencies. Several commentators have noted that the market is confused by the proliferation of both emergency and price responsive programs that are currently in the market place. Load coordinator program proposals that allow aggregators to “compete” to recruit bundled service customers into demand response programs create administrative hardships or conflicts between UDCs and aggregators that have not been resolved.
3. Uncertain Market clearing prices- Disagreements on the value of energy or demand reductions from DR program participants worsened during 2001 as new energy agencies and the CPUC could not find common ground on both what was to be valued (energy, capacity, day ahead calls, etc) or what it was worth.

D. Marketing Barriers

1. Most industrial customers are not interested in providing load reductions if it means interrupting service through old-fashioned interruptible programs without warning or in violation of the contract terms related to the duration of the interruption due to unforeseen emergencies. They would prefer to purchase other forms of insurance unless the programs become much more flexible and dependable.
2. Participants in California’s DR programs were quite frustrated by the lack of effective communications about what types demand response programs will be offered on a consistent basis (for more than one summer) and inconsistent policies with respect to the assessment of penalties for non performance. (Reference 8)
3. Many customers perceive that curtailing load cannot be accomplished without a significant drop in plant or personnel productivity. They are either unaware or not convince that most building systems have the technical capability of reducing loads by 10% with little or no effect on employee productivity.
4. Most utilities have expressed serious concerns (outside of regulatory arenas) about the prudence of spending money to recruit more customers into DR programs or tariffs under the current regulatory regime where cost recovery is at best highly uncertain.

E. Conclusions

There are a number of barriers to the achievement of increased demand response in California’s electricity market. The Energy Commission believes that most of these barriers could be quickly resolved over the next three years if the key policy agencies could agree on what must be done to resolve the policy barriers first and then letting other players work to resolve the remaining technical, administrative and marketing barriers. The next section describes some potential actions that could be taken by each agency to resolve these

V. What Concrete Actions should be taken by the Group to achieve more Demand Response in the Electricity Market?

Below we present a number of proposed actions that should be discussed and prioritized at the workshop. We suggest that parties first ask questions of clarification to ensure the proposed actions are understood, then comment on the relative importance or priority of moving ahead with specific actions or derivatives of them.

A. Proposed Actions to Mitigate or Eliminate Policy Barriers

Policy Barrier #1- There is no uniform vision held by key state agencies or the electric distribution utilities of where the electricity system is heading and how or if demand response should be included in that vision. Perhaps as a result, there is no uniform state policy on planning and implementation of Demand response programs and or how they should be integrated with tariff proceedings.

> **Action 1.1**- The Energy Commission, CPUC and CAISO should work together to develop a joint vision using the visions presented in section 3 as a starting place for more dialogue and a discussion of alternative visions.
>
> **Action 1.2** -The Energy Commission, CPUC and CAISO should make a commitment to integrating demand response programs or tariffs into the re-design or reform of wholesale markets in the form of a letter to FERC announcing their plans to achieve DR in the new market design.
>
> **Action 1.3**- The Energy Commission, CPUC and CAISO should meet to discuss how to develop a joint DR planning forum or series of coordinated policy proceedings that would set policy and approve programs over a multi year period.

Policy Barrier 2- There is a jurisdictional conflict between the CAISO and the California Public Utility Commission for design and approval of demand response programs/ tariffs.

> **Action Option 2.1**: Have a neutral third party (perhaps the Energy Commission or CPA) propose a division of oversight responsibilities. One suggestion that could be explored is to identify clear areas of oversight based on primary agency functions and a commitment for both agencies to meet where programs overlap.
>
> In this example CAISO would have jurisdiction over " reliability based" programs (to provide spinning reserve, and capacity reservation commitment from customers for emergencies, (examples (CPA spinning reserve proposal, OBMC and or direct load control). The CPUC would have jurisdiction over all price based response programs (including demand bidding, baseline demand response, and interruptible curtailable) and all dynamic pricing tariffs. CPUC and CAISO could then announce that they expect utilities to analyze and propose the

appropriate mix of DR programs and tariffs as part of their “ resource or reliability” plans to be reviewed in the CPUC’s procurement proceedings.

Policy Barrier 3 - There is some dispute about whether demand response programs and or dynamic tariffs will actually lead to significant reductions in electricity prices at the margin in the wholesale market. This dispute is exacerbated since there are no transparent wholesale markets in CA with enough sales volume to actually observe changes in wholesale prices as a function of demand.

Action 3.1- The Energy Commission and CPUC should work closely with the CAISO and CPA to ensure that whatever market design reforms are adopted produce a transparent wholesale market by January 1, 2003. Quarterly Status reports should be given to the heads of each agency by a task force created to work on this program.

Policy Barrier 4: No policy agreement exists on the best way to develop and implement a system of dynamic pricing tariffs for all customer classes and how to link the wholesale market prices to these tariffs for some or all classes.

Action 4.1: The CPUC and Energy Commission should jointly announce their intent to move toward making dynamic tariffs available to all customer classes within the next decade. More specific action in this area:

4.1a. Hold Workshops to develop model dynamic pricing tariffs for at least four customer classes, present to the CPUC by 1/1/03.

4.1b Expand the current procurement proceeding in phase 2 to perform an analysis of the need for dynamic tariffs to be phased in beginning by June of 2003.

The analysis required to produce tariffs in either of the above options could be considered either in a joint Energy Commission /CPUC proceeding or the CPUC’s second phase of the procurement proceeding transferring authority to purchase energy from CDWR to the incumbent utilities

The exact structure and timing of this phase-in of dynamic rates, their linkage to wholesale markets or proxies for them and the necessary meters would be determined in a proceeding. UDCs would be asked to propose two tariff choices for each customer class and then parties such as the Energy Commission or ORA could perform a detailed cost benefit analysis of their specific proposals. Specific rate designs to be considered but not limited to include:

a. Large and medium customers(>100kW) get three tariff choices-

(1) Hourly pricing,

(2) Time of use pricing with super critical peak for up to 80 hours

(3) Flat pricing with hedge premiums depending on the length of the tariff contract.

b. Residential and small customers get two choices-

(1) default time of use pricing with critical peak (CPP) rates for less than 80 hours, or

(2) flat annual rate plus payment of a monthly premium to guarantee annual stability and pay for the extra hedges needed to ensure costs are stable.

See Figure 10 for a graphical representation of critical peak pricing.

Policy Barrier 5- The current state policy related to the purchase and financing of meter improvements has not yielded a commitment by distribution companies or state energy agencies to deploy interval meters to the mass market. The Governor's metering program to install interval meters for customers in the 200 to 500 kW class has not led to more momentum in this area to install meter in smaller rate classes. This problem may be related to the fact that no workable dynamic tariffs have been proposed for the residential or small customer class.

Action 5.1- The CPUC and Energy Commission could announce their intention to design and implement a pilot program to test the effectiveness of critical peak pricing tariffs for a representative sample of customers in one or more IOU service territories. Expenses could be recovered using loan funds from CPA or through the rate base. Both agencies should carefully monitor customer acceptance and load impacts before moving ahead with decision to deploy the CPP tariff and interval meters and control equipment to support them on a system wide basis.

Action 5.2 : Metering vendors could be asked to respond to an RFP to deploy advanced metering systems to all customers in each IOU territory over a five year period. UDC's would select winning bidders and seek authority to recover the expenses of deploying the winning bids within the ongoing procurement proceeding.

Action 5.3 State agencies could seek to amend the current senate bill on dynamic tariffs (Torlakson, SB 1976) to more explicitly support introduction of dynamic pricing over the next few years.

Policy Barrier 6- Regulatory uncertainty exists about the costs and benefits of introducing dynamic pricing tariffs for some customers.

Action 6.1: Appoint an interagency staff team to both propose a set of dynamic tariffs for all customer classes and analyze the anticipated impact of these tariffs on demand and wholesale market prices and the related cost effectiveness of the tariffs for specific customer classes. They should use the vision on rates presented in Section 3 as a starting point. The Commissions should ask for a completed report by September 1, 2002.

Action 6.2- Energy Commission, CPUC and or utilities could agree to task an expert team to investigate the feasibility of shifting the “insurance premiums” consumers currently pay as part of a flat rate to guarantee reliability, from a social allocation basis where the insurance premium is included in everyone’s rate structure to a market driven basis where payment differs based on individual usage.

Action 6.3- The DR group could offer to brief any or all commissioners with questions about cost effectiveness by presenting the results of the benefit cost analyses prepared by Charles Rivers Associates and presented at the workshop. (Reference 9) This study showed that the deployment of meters and critical peak pricing led to the highest benefit cost ratios of any demand response / tariff mix.(Benefit cost ratios from the total resource cost perspective ranged from 1.7 to 3.5.)

Policy Barrier #7- Some regulators are uncertain that the deployment of demand response programs or dynamic tariffs is consistent with their desire to move back to a regulated generation market.

Action 7.1 Demand response team should develop and prepare briefings for each CPUC, Energy Commission, or CPA commissioner on the costs and benefits of dynamic pricing in both regulated and deregulated markets. Provide briefing to key legislators on request. (Our analysis shows that DR or Dynamic tariffs are likely to be equally as important in ensuring system reliability in either regulated or deregulated markets.)

B. Proposed Actions to Address Technical Barriers

Technical Barrier 1: Builders see no current need to design energy management systems to communicate with utility meters and or system notification networks in the event of pending reliability problems. In addition the cost of providing dimmable lighting ballast systems that are integrated into EM systems is seen as too high and or not cost effective.

Action 1.1: Energy Commission should begin a load management[2] (LM) proceeding by June 1 to set demand response goals at the system and customer/building level . Possible options to analyze include:

1. System wide standards that mandate that UDCs demonstrate the ability to shed up to 5% of system load requirement capability within 30 minutes of a call on an annual basis.

[2] The Energy Commission’s load management standards authority is described in Appendix 2.

2. Building level standards for new buildings could require each building to have the capability to automatically secure a 10% load drop at the building level within 30 minutes.
3. Interval metering requirements for all customer classes over a five to ten year implementation schedule.

The goal would be to have new LM standards adopted by 3/01/03 for use in the summer of 2003

Action 1.2- Energy Commission could include metering and controls requirements as part of its ongoing improvements to Building standard proceeding for all new buildings after 1/1/05. Consider requiring that all 100kW+ buildings have:

1. interval meters and communication (wireless) systems
2. link of meters to on site control of lighting and HVAC systems
3. Some form of energy information system that provides customers with information on load profile and cost per hour at their facility.

Action 1.3 Consider setting new building code requirements for single family homes and small commercial buildings (20kW to 100kW) including:

1. interval meters and or smart thermostats
2. specifying some minimum form of energy information system be available to customer either on site or on line.

Action 1.4 Energy Commission and utilities could jointly sponsor additional PIER research to develop lower cost sensors and ballasts to drive down the current costs of EMS systems linked to dimmable ballasts.

Technical Barrier #2 Some UDC's are skeptical that today's wireless metering technologies will prove to be reliable and cost effective . Particular problems are caused by urban communication dead spots or shadows which can slow data transfer.

Action 2.1- Prepare a report on the effectiveness of wireless metering technologies currently being installed in SCE and PG&E territories and suggest any needed improvements in hardware or network support.

Technical Barrier #3- Reserve requirements- It is unclear how, or whether, dynamic pricing tariffs and price-response demand programs can be counted toward satisfying WSCC operating reserve requirements.(isn't this a policy barrier?)

Action 3.1- Form a working group to explore dimensions of this problem with CAISO, WSCC members, and other interested parties.

Technical Barrier #4 -Immaturity in the "art" of estimating the extent of load reduction that may result from and emergency signal or critical peak period price signal reduces interest on the part of system operators and energy procurement agents.

Action 4.1 Build a better reporting system that can measure combined program drops at the substation level.

Technical Barrier #5 Customers are not yet familiar with the concept of monitoring loads and responding to load curtailments without sacrificing comfort or productivity.

Action 5.1 In order to facilitate more customer participation, load visualization and alarm techniques, and automatic control equipment must continue to evolve to make Demand response concepts more "user friendly."

C. Proposed Actions to Address Administrative Barriers

Administrative Barrier 1-Billing Constraints- UDCs could have trouble, in the near term, billing their customers using dynamic pricing tariffs if the tariff design was very complex or the number of participants exceeds a few hundred.

Action 1.1 There is probably a need to develop and adopt a short and a long term strategy. Pilot tests to test out billing systems for 100 to 500 customers should be completed before committing to universal deployment. Long term strategy should be to declare that UDC's will have to eventually upgrade their billing systems to handle increased number of customers on dynamic tariffs but the number and date will be set after the pilot tests are completed.

Administrative Barrier #2- Multiple DR programs are offered by UDC's and private aggregators to the public. To complicate matters they are overseen by different agencies- Several commentators have noted that the market is confused by the proliferation of both emergency and price responsive programs that are currently in the market place. Load coordinator program proposals that allow aggregators to "compete" to recruit bundled service customers into demand response programs create administrative hardships or conflicts between UDC's and aggregators that have not been resolved.

Action 2.1- Ask program managers to meet and recommend much more user friendly names and organizing concepts for the current batch of programs.

Administrative Barrier #3-Disagreements on the value of energy or demand reductions from DR program participants worsened during 2001 as new energy agencies and the CPUC could not find common ground on both what was to be valued (energy, capacity, day ahead calls etc) or what it was worth.

Action 3.1- Solve this dispute as part of either procurement proceedings at CPUC or as part of Energy Commission load management standards proceeding.

D. Proposed Actions to Address Marketing and Customer Acceptance Barriers

Marketing Barrier 1- Most commercial industrial customers are not interested in providing load reductions t in response to emergencies or price signals on a day to day basis as the crisis fades. However they may be interested if the rates are coupled with proposals to increase the use enhanced automation to control energy bills and increase occupant productivity.

> **Action 1.1**- Coordinate the deployment of the Energy Commission's existing enhanced automation campaign with UDCs and other agencies to maximize its effectiveness. This campaign is scheduled to kick off on June 1, 2002 and will provide information and case studies to targeted users and keep interest in new metering and control high.

Marketing Barrier 2- Large Users are quite frustrated by the lack of effective communications about what demand response programs will be offered on a consistent basis and inconsistent policies with respect to the assessment of penalties for non performance.

> **Action 2.1** - The agencies should meet and confer to decide if the demand response message for summer of 2002 and beyond could be coordinated through one agency or a private advertising firm.

Marketing Barrier 3 Many customers perceive that curtailing load cannot be accomplished without a significant drop in plant or personnel productivity. They are either unaware or not convinced that most building systems have the technical capability of reducing loads by 10% with little or no effect on employee productivity.

> **Action 3.1-** Coordinate the Energy Commission's Enhance Automation campaign with other agencies to sell the message that demand response does not have to hurt!

Marketing Barrier 4- Most utilities have expressed serious concerns (outside of regulatory arenas) about the prudence of spending money to recruit more customers into DR programs or tariffs under the current regulatory regime where cost recovery is at best highly uncertain.

> **Action 4.1-** Rely on the CPUC to resolve the utilities' credit problems in a timely manner**.**

E. Next Steps- Suggested Process to Refine and Implement the Action plan

1. Energy Commission staff should present plan at public workshops.

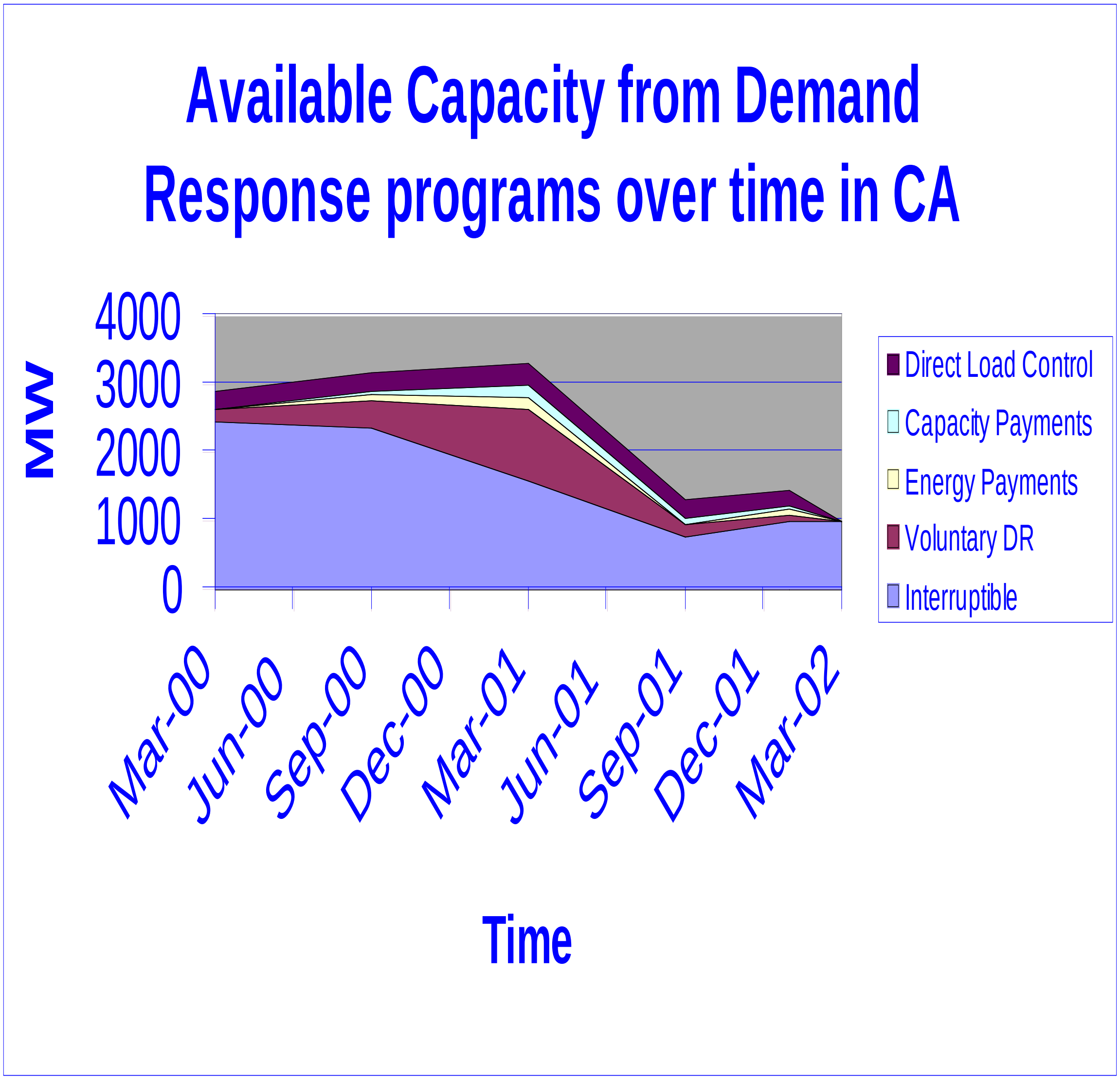
2. Discuss what are the highest priority action items and set a schedule for implementing them.

3. Revise report based on feedback and present final plan to all commissions for adoption by July 1, 2002. (Very good press opportunity here)

4. Interagency staff group works with agency heads to release a joint action plan by August 1, 2002- At this point the agency chiefs should attempt to sell the action plan to governor’s office.

Appendix A

DR capacity over the last two years



Appendix B

Energy Commission's Current Load Management Authority

(Section 25403.4 Warren Alquist act)

The Energy Commission shall adopt load management standard by regulation for a program of electrical load management for each utility service area. In adopting the standards the commission shall consider, but need not be limited to, the following load management techniques:

(1) Adjustments in rate structure to encourage use of electrical energy at off-peak hours or to encourage control of daily electrical load. Compliance with such changes in rate structure shall be subject to the approval of the Public Utilities Commission in a proceeding to change rates or service.

(2) End use storage systems that store energy during off-peak periods for use during peak periods.

(3) Mechanical and automatic devices and systems for the control of daily and seasonal peak loads.

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4. California Independent System Operator, Report on ISO declared emergencies for 2001: March 2002.
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9. Steve George and Ahmed Faruqui, Charles River Associates, The Economic Value of Dynamic Pricing for Small Customers (presentation at March 15th Workshop on Achieving Greater Demand Response in the California Market: Sacramento, Cal)
10. Penne Gullekson, AMR, Price Signals and Demand Response (Presentation at Energy Commission Demand Response Workshop) March 15, 2002.

Readers who want to access some of these presentations via the internet can download them at http://www.energy.ca.gov/peakload/documents/2002-03-15_presentations/